RPSEA

Final Report

RPSEA Project 11122-53

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An Integrated Decision Support Tool for Unconventional Natural Gas Development with Focus on Flowback and Produced Water Characterization, Treatment and Beneficial Use

RPSEA 11122-53

August 31, 2016

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ABSTRACT

Development of unconventional gas resources, such as shale gas, is currently one of the most rapidly growing trends in oil and natural gas exploration and production. Exploration of shale gas requires significant quantities of water for hydraulic fracturing, while large volumes of produced water are generated during gas production. Treatment and beneficial use of hydraulic fracturing flowback and produced water provides pronounced opportunities for sustainable unconventional gas operations while minimizing potential impacts to environment, local water sources, and public health. Considering the broad variety of treatment processes and the wide spectrum of flowback and produced water quality, selecting the treatment and management options involves a complex decision-making process that requires understanding of treatment technologies, water quality, reuse requirement, and consideration of multiple criteria, constraints, objectives, and functions.

This project developed an integrated decision-support tool (i-DST) to assist in selection of treatment technologies and evaluation of the feasibility for beneficial uses of hydraulic fracturing flowback and produced water. The i-DST consists of four basic modules: Water Quality Module (WQM), Treatment Selection Module (TSM), Beneficial Use Screening Module (BSM), and Beneficial Use Economic Module (BEM). The WQM has a built-in water quality database with stored data for produced water and hydraulic fracturing flowback water in the major oil and gas producing basins. The TSM is designed to select proper treatment technologies based on feed water quality, user preferences, and desired product water quality. The BSM stores beneficial use options, such as potable use, irrigation, hydraulic fracturing, and thermal power plant cooling water. Each of them is assigned appropriate product water quality requirements that the treatment train needs to achieve. The user can also enter specific water quality parameters of interest. The BEM calculates costs based on selected treatment technologies, desired product water flow rate, and economic inputs assigned by user. This cost estimate was developed to compare the treatment processes at a Class 5 level representing Planning to Feasibility level information with an estimated accuracy range between -30% and +50%.

The Marcellus Shale in Pennsylvania and the Barnett Shale in Texas were selected as case studies to determine the treatment technologies and beneficial use options of flowback and produced water considering realistic site-specific conditions, assumptions such as well numbers, water demands, flowback and produced water quality and quantity, disposal availability, and costs. Flow rate and water quality are the two primary factors affecting the costs and feasibility of treating and beneficial use of flowback and produced water. The case studies demonstrated that the i-DST is a useful screening tool to select treatment trains and estimate costs for reuse scenarios.

The project final report consists of three sections: 1) an overview of the flowback and produced water management, treatment and beneficial use for major shale gas development basins in the U.S.; 2) description of the logistics and modules of the integrated decision support tool (i-DST); and 3) case studies of Marcellus Shale in Pennsylvania and Barnett Shale Play in Texas using the i-DST. The final products of the project also include a User Manual of the i-DST, and a report on Technical Assessment of Produced Water Treatment Technologies (2nd Edition).

The final products of the project can be downloaded at the RPSEA website: http://www.rpsea.org/; and the Produced Water Treatment and Beneficial Use Information Center: http://aqwatec.mines.edu/produced_water/tools/download/DST-2.0.html.

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DISCLAIMER

The outputs and results obtained from this study are meant for project screening purposes only as relevant information gathered for these modules are based on limited projects and best engineering judgment. Actual project will contain details not captured in this analysis that may affect the treatment of produced water and hydraulic fracturing flowback water, regulatory compliance, project feasibility, and overall costs of the project.

ACKNOWLEDGEMENTS

The authors are very grateful for the technical and financial support we received from our industrial partners and stakeholders to conduct this study. Without their input this study would not have been possible. We are also thankful to the Research Partnership to Secure Energy for America (RPSEA) for funding this study.

SECTION 1

OVERVIEW OF SHALE GAS FLOWBACK AND PRODUCED WATER MANAGEMENT, TREATMENT AND BENEFICIAL USE

1.1 INTRODUCTION

Shale gas, known as natural gas production from hydrocarbon-rich shale formations, has become one of the most rapidly expanding energy resources today. According to the Energy Information Administration Annual Energy Outlook Report (EIA, 2012), shale gas production in the U.S. is projected to increase from 23% in 2010 to 49% in 2035. Conventional oil and gas has been produced from permeable geological formations for decades, which is still playing an important role; however, the advances in directional drilling and breakthroughs in hydraulic fracturing have allowed expansion of unconventional gas production from deep and less permeable shale formations. This new gas development has brought changes and challenges to many relevant fields, including environmental issues, which is a particular concern to producers, regulators and the public. Most unconventional gas wells in both mature and new plays are using hydraulic fracturing as a technique for stimulation, which involves injection of water containing additives under high pressure. After the drilling process when the pressure is released, the injected water comes out from cracks in deep shale formations, with minerals, organic matters, salts, and added chemicals, which is called flowback and produced water.

Flowback and produced water are the largest volume byproducts associated with oil and gas exploration and production, which can either be a waste or a resource, depending on how they are managed. Current shale gas well drilling requires approximately 65,000 to 600,000 gallons (246 to 2,270 m^3) of water, and hydraulic fracturing requires 3,000,000 to 6,000,000 gallons (11,356 to 22,712 m^3) of water, of which 6% to 85% flows back to the surface and becomes flowback (short-term) and produced (long-term) water, which is estimated to be in the range of 15 to 20 billion barrels (2.4 to 3.2 billion m^3) per year in the U.S. (Clark and Veil, 2009). Due to its highly variable quality (salts, petroleum hydrocarbons, metals, chemical additives, suspended and colloidal solids) and quantity, flowback and produced water management poses significant challenge to both producers and regulators. Depending on availability, economics, and regulatory requirements, currently there are four major produced water management options, including 1) deep well injection, 2) discharge to nearby surface water bodies, 3) disposal of commercial or municipal wastewater treatment facilities, and 4) reuse for a future hydraulic fracturing job, with or without treatment.

Water shortage has been affecting many regions in the U.S., which also leads to water availability challenges to oil and gas industry. Continuous drought in southwestern U.S. has affected oil and gas production significantly, because drilling and hydraulic fracturing operations demand substantial amount of water. Water conflicts between Barnet Shale and Eagle Ford Shale is one example of the challenges, as they share the same surface water system (Arthur, 2011).

Beneficial reuse of flowback and produced water is in great need. In New Mexico, producers are taking flowback and produced water as a resource of water for well development because it costs less than using freshwater for hydraulic fracturing and drilling. Further northeast, Marcellus Shale now reuses over 90% flowback and produced water for future fracturing jobs. All evidences demonstrate the urgent need to reuse flowback and produced water, as water shortage has become critical for oil and gas exploration and production.

There are many factors affecting the decision on beneficial reuse of flowback and produced water, including suitable technologies for water treatment, freshwater availability and location, flowback and produced water quality and quantity, availability of commercial treatment and disposal facilities, and regulatory and institutional issues.

1.2 OBJECTIVE

This study aims to understand the challenges of flowback and produced water management in major basins by looking into detailed site conditions, and to investigate the prospect of beneficial reuse of flowback and produced water.

1.3 METHODOLOGY

A comprehensive literature review was conducted for data and information collection, including peer-reviewed journal articles, white papers, conference proceedings and presentations, webpages, news release, technical reports, government documents, and data from research institutions and producers. Five major shale gas-producing basins are studied, including Marcellus, Fayetteville, Haynesville, Barnett, and Eagle Ford.

1.4 RESULTS AND DISCUSSION

Considered as the largest volume of waste byproduct from shale gas industry, flowback and produced water is historically managed to be disposed of rather than beneficial reuse. Management of flowback and produced water depends on a variety of factors, including the quality and quantity of the waste stream, the type and location of infrastructure, the availability of injection wells and treatment facilities, regulations related to wastewater discharge and transportation, and the overall shale gas development (Rahm et al., 2013).

In recent years, beneficial reuse of flowback and produced water has increased. This trend is driven by fresh water shortage, nationwide drought, increased fresh water demand for hydraulic fracturing, regulations and policies, environmental concerns, rapid development of unconventional gas production, and public perception. In this study, wastewater management, treatment options and challenges are analyzed and discussed for major shale gas producing plays.

1.4.1 Marcellus Shale

The Marcellus Shale is the largest natural gas producing play in the U.S., and is rapidly growing in recent years, especially in Pennsylvania. New wells drilled in Pennsylvania have been rapidly increasing since 2007 (Figure 1.1), when breakthrough on hydraulic fracturing techniques occurred (Veil, 2013). Total shale gas producing wells in Pennsylvania was 6,391 as of Oct. 10, 2013 (Amico et al., 2013).

Along with the rapid growth of shale gas production comes an increasing amount of water demand, mainly for hydraulic fracturing, resulting in a substantial amount of flowback and produced water. Average fresh water demand for drilling a new well is estimated 80,000 to 85,000 gallons (300 to 322 m^3), while hydraulic fracturing needs vary from 3,300,000 to 5,500,000 gallons (12,500 to 20,820 m^3), according to shale gas producers in the Marcellus Shale play. Produced water production raised from 18,104,507 barrels (2,158,781 m^3) in 2009 to 10,720,653 barrels (1,278,330 m^3) in the first half of 2013 (Mantell, 2011).

Flowback and produced water quality from the Marcellus Shale is relatively well characterized by laboratory testing in the past few years. Flowback water coming out immediately after fracturing has a moderate to poor quality, with high total dissolved solids (TDS) at approximately 40,000 ppm to 90,000 ppm but low total suspended solids (TSS) (approx. 160 ppm). Hardness varies from moderate to high concentrations. Long-term produced water also has a high TDS at over 120,000 ppm (Mantell, 2011).

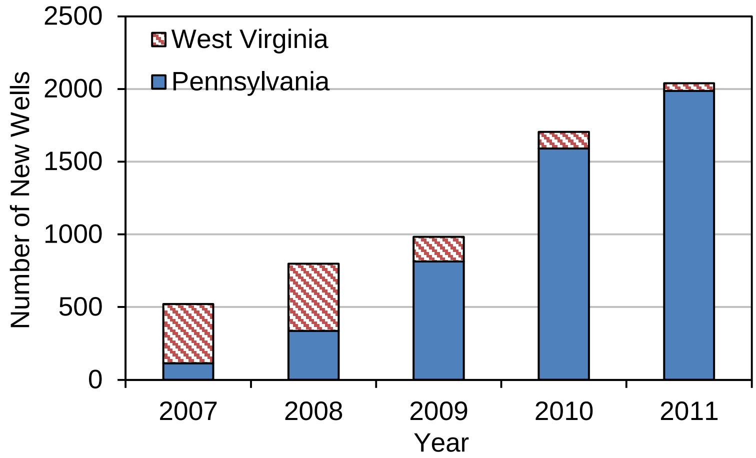

Figure 1.1 Number of new wells drilled in Marcellus Shale from 2007 to 2011. *Source: data adopted from Veil, 2013*

Flowback and produced water management in the Marcellus Shale region has been successful. As shown in Table 1.1, compared to 2009 when reuse ratio of wastewater was only 15% to 20%, around 90% of the flowback and produced water were reused/recycled in the year 2013, mainly saved for new well drilling (Veil, 2013). Beneficial reuse of the wastewater makes up to approximately 10% of the water needed for hydraulic fracturing job for a new well.

Table 1.1 Flowback and produced water management in Marcellus Shale between 2009 and 2013

Wastewater Management Options	Flowback Water (%)		Produced Water (%)	
	2009	2013	2009	2013
Reuse	21.3	26.8	15.3	75.1
Centralized Treatment for Recycle	0.0	70.1	0.0	12.8
Injection Wells	0.2	2.7	0.7	12
Discharge	78.5	0.4	84	0.1

Source: data adopted from Veil, 2013

Flowback and produced water needs to be treated before reuse or disposal. In Marcellus Shale areas, reuse for hydraulic fracturing needs oil/gas-water separation, filtration, and dilution as treatment methods. Dilution of the wastewater is aimed at decreasing contaminant concentrations to an acceptable level for hydraulic fracturing, and is the most common way to treat flowback and produced water for beneficial reuse. Disposal well injection is also in use in Marcellus, with annual volume of approximately 2.5 million barrels (397,400 m^3).

1.4.2 Barnett Shale

During its development, the Barnett Shale became a leading shale gas production field in the U.S. in 2008, when horizontal drilling techniques were first adapted and refined. By the end of September 2013, there are in total 17,332 shale gas wells in Barnett Shale (Figure 1.2), producing more than 5.3 billion cubic feet (150 million m^3) shale gas per day (RRC, 2013a, b).

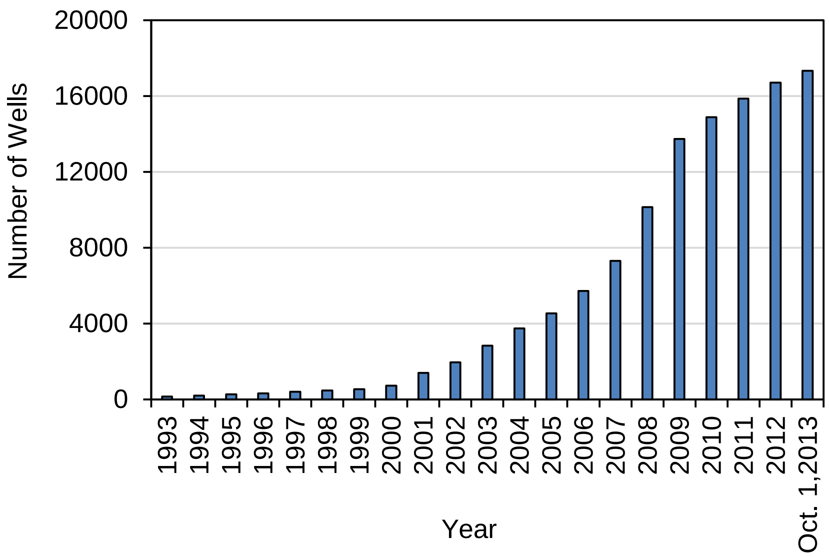

Figure 1.2 Number of wells in Barnett Shale from 1993 to Sep 30, 2013. *Source: Texas Railroad Commission Production Data Query System (PDQ)*

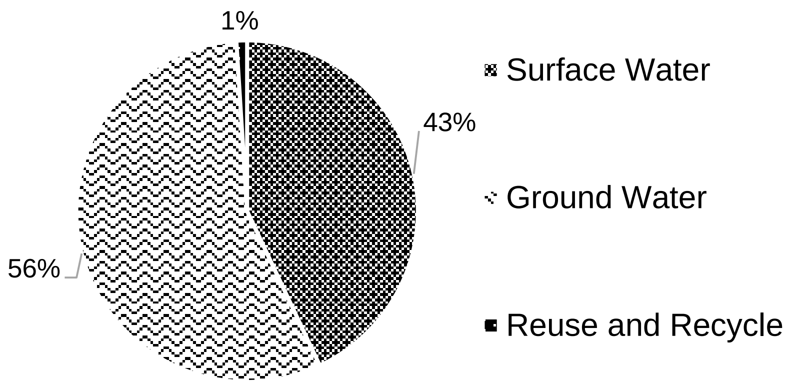

Figure 1.3 Water sources used in the Barnett Shale for natural gas development. *Source: Hayes, 2010.*

Drilling new wells in Barnett Shale requires around 250,000 gallons (950 m^3) of water per well, and hydraulic fracturing requires 3,800,000 gallons (14,385 m^3) per well, all of the water comes from groundwater (Mantell, 2011). Current fresh water availability in Barnett Shale is not a limiting factor for oil and gas production, because of the abundant surface and ground water resources in Texas (Figure 1.3).

In Barnett Shale, initial return rate of hydraulic flowback water is relatively small, gradually increasing over a long period of time. Due to its formation characteristics, high volume of natural formation water exists near the shale play, which would flow into the well site becoming produced water. Flowback and produced water in Barnett Shale has relatively low TSS, TDS and chlorides, however, increasing significantly over time, from 50,000 and 25,000 ppm in the beginning to 140,000 and 80,000 ppm at the end of well lifetime, respectively (Mantell, 2011).

Disposal well injection is the most common choice for Barnett Shale producers because of its economics and availability. Some producers are reusing a small amount of wastewater, but many have just started considering beneficial use options. The Railroad Commission of Texas recognizes concerns over water use by the oil and gas industry and encourages recycling projects aimed at reducing the amount of fresh water used in exploration and production (RRC, 2013c). Besides, nationwide drought in the U.S. is also an incentive for beneficial use, with potential water conflicts between shale plays within Texas, such as in the Eagle Ford.

1.4.3 Fayetteville Shale

Fayetteville Shale is an unconventional natural gas producing shale in Arkansas with a steady increase in production since 2009 (Figure 1.4). Total number of wells completed in 2010 was 3,017 (AGS, 2010, Veil, 2011).

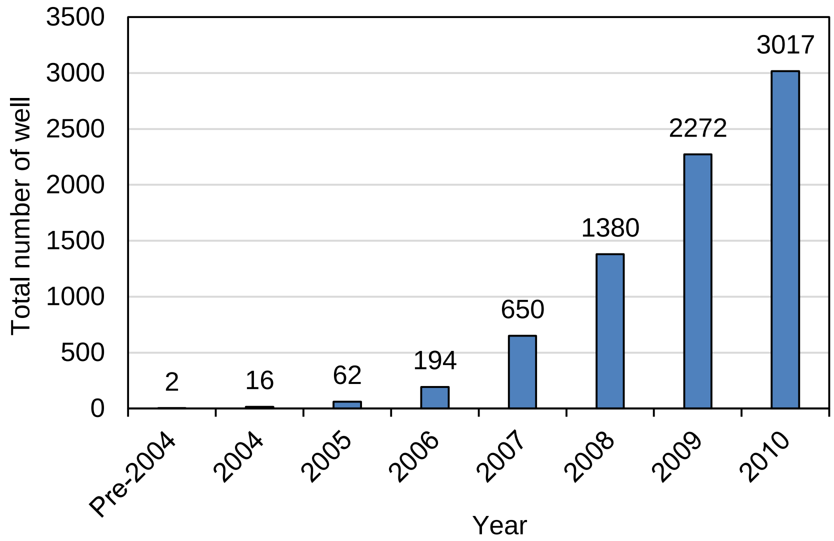

Figure 1.4 Number of New Wells Drilled in Fayetteville Shale from 2004 to Dec 2010.
Source: data adopted from Arkansas Geological Survey, 2010

Water required by well drilling in Fayetteville is 60,000 to 65,000 gallons (227 to 246 m^3) per well, and hydraulic fracturing requires 2,900,000 to 4,900,000 gallons (10,978 to 18,549 m^3) per well. Annual water demand is estimated to be 4.1 to 5.8 billion gallons (15.5 to 22.0 million m^3) per year (Veil, 2011). Generally, water supply should be sufficient to support the development of Fayetteville, although water restriction may exist in different areas and seasons (Veil, 2011). There are also water storages that producers collect and store water during times of abundance, and save for drought periods (Veil, 2011).

Flowback and produced water quality in Fayetteville Shale is better than that from other shale plays, with TDS between 10,000 to 20,000 ppm and chloride 10,000 ppm (Mantell, 2011). Most of the wastewater is injected by disposal wells.

1.4.4 Haynesville Shale

Haynesville Shale locates in northern Louisiana (65%) and eastern Texas (35%). By mid-2011, approximately 1820 shale gas producing wells had been drilled in Haynesville Shale. With more than 10,000 feet (3,048 m) depth of the shale formation, drilling water demand is significantly higher than other shale plays, from 600,000 to 1,000,000 gallons (2,271 to 3,785 m^3) per well (Nicot and Scanlon, 2012). Hydraulic fracturing water demand is about 5,000,000 gallons (19,000 m^3) per well (Mantell, 2011).

Initial flowback water is less significant, approximately 250,000 gallons (950 m^3) per well, but with poor quality (high TDS, TSS, and chloride). Scaling tendency is also very high, with calcium approximately 8,000 ppm and magnesium approximately 500 ppm (Mantell, 2011). Very poor flowback and produced water quality makes it very unattractive for treatment and reuse, both short and long term. Drilling mud, however, has a relative high quality and larger volume, which makes it more feasible for reuse.

1.4.5 Eagle Ford Shale

Eagle Ford Shale is a relatively new shale gas-producing field in Texas, with a rapid development. Starting from 2008 when the discovery well was drilled, 1040 wells had been drilled and producing shale gas in Eagle Ford Shale by 2012 (Nicot and Scanlon, 2012).

Drilling in Eagle Ford Shale requires 125,000 gallons (473 m^3) of water per well, and hydraulic fracturing requires between 2,000,000 to 13,700,000 gallons (7,570 to 51,860 m^3) per well (Arthur, 2011, Nicot and Scanlon, 2012). Annual net water use was 26.4 billion gallons (100 million m^3) in 2012.

Wastewater quality in Eagle Ford Shale is still under evaluation, but preliminary study showed the potential for beneficial use. Even though fresh water availability has not yet become a major issue, nationwide drought has already showed potential water conflicts between Eagle Ford Shale and Barnett Shale. During the 2011 drought, many operators in Eagle Ford Shale were forced to "buy water from farmers, irrigation districts and municipalities" (Wang and Krupnick, 2013). And with the startup of Eagle Ford Shale, water shortage in Texas is very likely to occur (Wang and Krupnick, 2013).

1.5. SUMMARY AND CONCLUSION

Shale gas is becoming an important energy source for the U.S., as predicted to grow from 23% of total energy supply in 2010 to 49% in 2035. The rapid growth has caused water issues, with both fresh water uses and wastewater management. Table 1.2 summarizes gas production, water demand and quality, management options, and potentials for beneficial use in five major shale plays.

There are four options that are most widely adopted for flowback and produced water management. Majority of beneficial use of flowback and produced water is for future fracturing job, after mixing the treated water (after oil/water separation and other processes) with freshwater to meet the fracturing standard.

Operators in Marcellus Shale are reusing over 90% of flowback and produced water, mainly saving for future hydraulic fracturing jobs; 10% of the water for drilling new wells comes from the reused water. Shale plays in Texas, including Barnett Shale, Eagle Ford Shale, and Haynesville Shale, are using disposal injection as their primary choice, mainly due to economic consideration and availability of disposal wells. Many operators, however, are considering beneficial reuse because of potential water shortage. In addition, federal, state and local agencies are or have been making regulations and policies on oil and gas wastewater management (Rahm and Riha, 2012, Clark et al., 2012). Under Clean Water Act and Safe Drinking Water Act, the U.S. Environmental Protection Agency (EPA) is developing a proposed rule to control flowback and produced water management (USEPA, 2013). Besides, state governments and agencies are also developing regulations, to better manage oil and gas operations. Regulations and policies differ significantly among states, due to different situations and water issues (Tiemann and Vann, 2013).

Flowback and produced water management is facing significant challenges, involving regulatory, economic and technical factors, such as:

- Both rapid development of shale gas production and nationwide droughts have challenged fresh water availability for exploration and production. Without proper management, availability of fresh water will hinder future oil and gas production due to increasing water demands for drilling and hydraulic fracturing.
- Disposal options and capacities are limited. Regulated by Underground Injection Control Program via the Safe Drinking Water Act (SDWA), only eight deep-injection wells in Pennsylvania are permitted to take oil and gas waste, and only five of them are active (Philips, 2012). Besides, earthquakes are recorded triggered by deep injection wells in Texas, New Mexico, New York, Nebraska, Colorado and Ohio, and possibly in Oklahoma, Louisiana and Mississippi (Nicholson and Wesson, 1951). Therefore, the currently available disposal options may not be able to meet the projected shale gas growth in the future.
- Cost-effective and viable technologies are in urgent needs to treat flowback and produced water with high TDS, organics, TSS, and scaling tendency. Current commercially available treatment technologies are energy intensive and often cost inhibitive. Innovative technical solutions need to be developed to tackle the difficult-to-treat flowback and produced water.
- It is critical to thoroughly understand and characterize the water quality of shale gas wastewater. The flowback and produced water quality is highly variable yet complex, also due to the chemicals added for drilling and hydraulic fracturing. In addition, advanced analytical methods need to be developed and standardized for accurate measurement of the contaminants in a highly saline environment, in particular organic contaminants, for which very limited information is available.
- Beneficial reuse requirements need to be well understood and developed. Potential beneficial use options such as hydraulic fracturing, irrigation, industrial uses, have the water quality requirement based on conventional water supplies. The water quality requirements may need modification to adapt to produced water and flowback water. These standards dictate the selection and design of treatment processes.
- Environmental and health impact of beneficial use applications (e.g., irrigation, municipal and industrial uses) needs to be evaluated in order to reduce the liability issues and protect environment and public health.

Treatment and beneficial use of flowback and produced water is becoming an attractive solution for sustainable development of shale gas resources. The challenges with respect to technologies, economics, environment, and regulations however should be addressed for beneficial use to be technically viable and economically attractive.

Table 1.2 Summary of produced water management in major shale plays

Shale Plays	Marcellus	Barnett	Fayetteville	Haynesville	Eagle Ford
Production Wells	Total wells: 9,715 by Oct 2013; Rapid growth in Pennsylvania since 2008	Total wells: 17,332 by Oct 2013; steady growth since 2009	Total wells: 3,017 by 2010; rapid growth since 2007	Total wells: 1,820 by mid 2011	Total wells: 1,040 by 2012. New shale play, rapid growth
Water Demand per well	80,000 - 85,000 gal for drilling; 3.3 – 5.5 Mgal for fracturing	250,000 gal for drilling; 3.8 Mgal for fracturing	60,000 to 65,000 gal for drilling; 2.9 to 4.9 Mgal for fracturing	600,000 - 1,000,000 gal for drilling; 5 Mgal for fracturing	125,000 gal for drilling; 2-13.7 Mgal for fracturing
Water Quality	TDS: 40 - 90 g/L short term, 140 g/L long term; TSS: 160 ppm; Scaling tendency: moderate	TDS: 50 – 140 g/L; TSS: low; Scaling tendency: moderate; Cl^-: 25 – 80 g/L	Good quality. TDS: 10 – 20 g/L; TSS: Low; Cl^-: 10 g/L.	Very poor quality. High; TDS & TSS: High; High scaling tendency	Under evaluation, high beneficial use potential according to preliminary studies
Current Status of Disposal	Disposal well injection, a small portion to wastewater treatment plant	Disposal well injection for most flowback and produced water			
Current Reuse and Potential	Over 90% of flowback and produced water are reused, most of which are stored for future hydraulic fracturing.	No reuse, but have a high potential because of new regulations and potential water shortage due to droughts	No reuse, but have a high potential because of new regulations and potential water shortage due to droughts	No reuse. Poor quality makes it less attractive. Drilling mud is more feasible for reuse for its relative high quality	No reuse, but have a high potential because of new regulations and potential water shortage due to droughts
Current Treatment Technology for reuse	Oil/gas - water separation; filtration; dilution with freshwater	Not available			

ACKNOWLEDGEMENT

The authors thank Dr. Engle Mark (USGS), John Veil (Veil Environmental, LLC), Corrie Clark and Christopher Harto (Argonne National Laboratory) for technical advices.

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SECTION 2

LOGISTICS AND MODULES OF THE INTEGRATED DECISION SUPPORT TOOL (i-DST)

2.1 INTRODUCTION

Sustainable development of oil and gas production requires understanding thoroughly produced water quality, selecting appropriate treatment technologies, and establishing environmentally sound management strategies. Considering the broad range of treatment processes and the recent technological advances, the industry demands a clear guidance and tools to assist in evaluation and selection of treatment technologies to meet their site-specific reuse needs. Besides treatment capacity and removal efficiency of contaminants, other factors affecting the selection of treatment technologies include technology industrial status (commercially available or under development), adaptability, feasibility, energy consumption, capital/operational and maintenance costs, footprint, skilled labor requirement, infrastructure requirement, waste production and disposal, as well as user preferences. Selecting the treatment and management options involves a complex decision-making process that requires the consideration of multiple constraints. Thus an integrated decision-support tool (i-DST) is needed to assist in selecting treatment technologies and evaluating the feasibility of potential water uses.

An integrated DST (i-DST) was previously developed for treatment and beneficial use of coalbed methane (CBM) produced water (Drewes et al., 2011; Dahm et al., 2011; Plumlee et al., 2014). It included a comprehensive water quality database for several major CBM basins in the U.S. This computerized produced water management tool could assist users, including gas producers, water utilities, government agencies, and the public, in assessing the characteristics of produced water, treatment processes, costs, environmental and institutional issues associated with treatment and beneficial use of CBM produced water. The i-DST framework provided a quick analysis and screening of various produced water treatment and management options.

In this study, the i-DST was upgraded with more functions and user choices, and further developed and enhanced beyond the CBM produced water management to shale gas and other unconventional resources. The i-DST is a user-friendly tool developed on easily accessible excel VBA platform. The tool was developed and tested to be compatible to Windows platform. This section provides an overview of the modules of the i-DST. For detailed operation of the tool, users may refer to the User Manual.

2.2 MODULES OF THE i-DST

The i-DST consists of four basic modules: Water Quality Module (WQM), Treatment Selection Module (TSM), Beneficial Use Screening Module (BSM), and Beneficial Use Economic Module (BEM) (Figure 2.1). Each module builds off of information input as well as output from previous module(s), and together the i-DST assesses the feasibility of utilization of hydraulic fracturing flowback and produced water for beneficial uses.

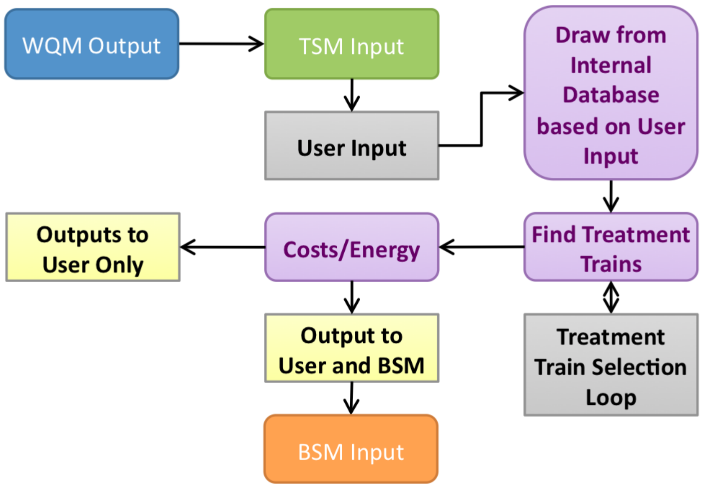

Figure 2.1 Simplified schematic diagram of the i-DST

2.2.1 Water Quality Module (WQM)

2.2.1.1 Developing Water Quality Module (WQM)

The Water Quality Module (WQM) was built upon a composite geochemical database previously developed for CBM produced water (Drewes et al., 2011; Dahm et al., 2011; Plumlee et al., 2014). It was created with 3,255 entries, covering the major CBM basins in the Rocky Mountain region, including:

- Powder River Basin in Montana and Wyoming
- Raton Basin in Colorado and New Mexico
- San Juan Basin in Colorado and New Mexico

The WQM includes a comprehensive information on 58 water quality parameters and constituents such as field measurements (e.g. pH, temperature, conductivity, and dissolved oxygen), metals, non-metals, organics, and radionuclides (Dahm et al., 2011).

In this study, the WQM was expanded with additional 6,517 entries for water quality data of flowback and produced water from the major oil and gas producing basins in the U.S., including:

- Barnett Shale Play in Texas
- Lansing-Kansas City Formation in Texas
- Marcellus Shale in Pennsylvania and West Virginia
- Morrow Shale in Anadarko Basin, Oklahoma
- Organic-rich Shale in Pennsylvinia, New York, and Ohio
- Permian Basins in Texas and New Mexico
- Tuscarora play (tight gas) in Pennsylvania

- Woodford Shale in Oklahoma

The water quality data were collected through literature review, from research institutions and producers, the U.S. Geological Survey (USGS) National Produced Waters Geochemical Database v2.1 (Provisional), Marcellus Shale Coalition Shale Gas Produced Water Database, New Mexico Water and Infrastructure Data System, New Mexico Oil Conservation Division, and other literature (Li, 2013; Mantell, 2011).

Of the 161,915 produced water quality data sets in the USGS database, 2,723 sets are for shale gas, organic rich shale, and tight gas, distributed in Oklahoma, Pennsylvania, New York, Ohio, and Texas. The final shale gas produced water quality database incorporated into the i-DST has 78 water quality parameters and constituents. A statistical analysis was conducted for the produced water database. The maximum, minimum, average, 25th, 50th, and 75th percentile values for each parameter and constituent were calculated by state and shale formation, and were included in the i-DST for users to choose. The measured TDS concentration of shale gas produced water reported data averages 84,870 mg/L. with the highest TDS value of 345,000 mg/L, and the lowest value of 390 mg/L.

In addition to the built-in water quality data, the tool also allows users to enter their own feed water data and target water quality requirement. The i-DST identifies and provides the list of constituents that require treatment through comparison of feed and target water quality.

2.2.1.2 Quality Assurance and Quality Control of the WQM

Quality assurance and quality control (QA/QC) for the USGS database was conducted before the USGS released the database and was described in detail in an explanatory documentation (Blondes et al., 2014). Datasets with charge balance error exceeding ±5% were flagged but not removed from the database. Total number of sets of shale gas flowback and produced water quality is 2,723, of which 1,688 has charge balance error over ±5%, which is about 62.1% of all datasets. Number of datasets exceeding standards is shown in Table 2.1.

Table 2.1 QA/QC on the produced water quality data from the USGS database

Standard	Exceedance
pH 4.5 – 10.5	2
Mg < Ca	32
K < Cl	7
K < 5xNa	3
Charge balance error < ±5%	1,688

Source: adopted from Blondes et al., 2014

QA/QC of the Marcellus Shale Coalition Produced Water Database was conducted through the Field Sampling and Analysis Plan and the Quality Assurance Project Plan developed, reviewed, and finalized by the companies of the Appalachian Shale Water Conservation and Management Committee (ASWCMC), Pennsylvania Department of Environmental Protection (PADEP), and West Virginia Department of Environmental

Protection (WVDEP). Flowback and produced water samples were collected by a single engineering company (URS) and water quality analysis was conducted by a PADEP and WVDEP certified environmental testing laboratory. Charge balance error calculation showed that, of the 95 data sets, 55% had CBE over 5%, 36% over 10%, and 19% over 20% (Blondes et al., 2014).

Possible causes for electroneutrality imbalance are: 1) lab errors included serious or systematic errors during analysis; 2) some major ions were not measured; 3) using unfiltered samples that contained particular matter, which dissolved during addition of acid for sample preservation or preparation. In this case study, datasets with all exceedance other than charge balance error were eliminated, because the exceedance of charge balance error in the USGS database were primarily caused by missing data of major ions, and would not affect statistical analysis of the data.

2.2.2 Treatment Selection Module (TSM)

The Treatment Selection Module (TSM) is designed to select proper treatment technologies based on feed water quality, user preferences, and desired product water quality. The TSM includes 62 processes as stand-alone pretreatment, desalination and post-treatment, as well as integrated and commercial treatment packages. A list of the technologies is summarized in Table 2.2.

These technologies were evaluated based on a comprehensive literature review and industry interviews on the current and emerging technologies for produced water management, treatment, and beneficial use. The technical evaluation criteria include commercial status of technology and applications; applicable feed and expected product water quality; removal efficiencies of key constituents; infrastructure considerations (modularity, mobility, building or shelter); energy use and consumption; chemical demand; life cycle and costs; O&M considerations (ease of operation, reliability, etc). Please refer the technology description, evaluation criteria, and case studies in the Technology Assessment Report.

In the TSM, each technology is assigned removal efficiency for each contaminant corresponding to different TDS bins. To better understand the salinity levels and more accurately determine desalination technologies, TDS levels are classified into five TDS bins, defined as Bin 1: TDS < 8,000 mg/L; Bin 2: 8,000 – 25,000 mg/L; Bin 3: 25,000 – 40,000 mg/L; Bin 4: 40,000 – 70,000 mg/L; and Bin 5: TDS > 70,000 mg/L. The classification is based on the removal capacities of different water desalination technologies, such as 25,000 mg/L for brackish water reverse osmosis (BWRO), 40,000 mg/L for seawater reverse osmosis (SWRO), 70,000 mg/L for thermal distillation and forward osmosis (FO). Desalination cost of feed water in the higher bins could be significantly higher than that in the lower TDS bins.

Table 2.2 List of produced water treatment technologies

Stand-alone/primary	Multi-technology processes
Basic Separation	**Enhanced distillation/evaporation**
○ Hydrocyclone	○ GE: MVC
○ Flotation	○ Aquatech: MVC
○ API Oil/Water Separator	○ Aqua-Pure: MVR
○ Coagulation and Chemical Softening	○ 212 Resources: MVR
○ Electrocoagulation (EC)	○ Intevras: EVRAS evaporation units
○ Settling	○ AGV Technologies: Wiped Film Rotating Disk
○ Media filtration	
Biological Treatment	○ Total Separation Solutions: SPR – Pyros
○ Activated Sludge	**Enhanced recovery pressure driven**
○ Biological Aerated Filters (BAF)	○ Dual RO w/ chemical precipitation
○ Membrane Bioreactor (MBR)	○ Dual RO w/HEROTM: High Eff. RO
○ Sequencing Batch Reactor (SBR)	○ Dual RO w/ SPARRO
○ SBR-MBR	○ Dual pass NF
Membrane Separation	○ FO/RO Hybrid System
○ High pressure membranes	**Commercial treatment RO-based processes**
▪ Seawater RO	○ CDM
▪ Brackish water RO	○ Veolia: OPUS™
▪ Nanofiltration (NF)	○ Eco-Sphere: Ozonix™
▪ VSEP	○ GeoPure Water Technologies
○ Electrochemical charge driven membranes	
▪ Electrodialysis (ED), ED reversal (EDR)	
▪ Electrodionization (EDI)	
○ Microfiltration/ultrafiltration	**Commercial Treatment IX-based processes**
▪ Ceramic	○ EMIT: Higgins Loop
▪ Polymeric	○ Drake: Continuous selective IX process
○ Thermally driven membrane	Eco-Tech: Recoflo® compressed-bed IX process
▪ Membrane distillation (MD)	
○ Osmotically driven membrane	○ Catalyx/RGBL IX
▪ Forward osmosis (FO)	**Miscellaneous Processes**
	○ Evaporation
Thermal Technologies	○ Infiltration ponds
○ Freeze-Thaw	○ Constructed wetlands
○ Vapor Compression (VC)	○ Wind aided intensified evaporation
○ Multi effect distillation (MED)	○ Aquifer recharge injection device (ARID)
○ MED-VC	○ SAR adjustment
○ Multi stage flash (MSF)	○ Antiscalant for oil and gas produced water
○ Dewvaporation	○ Capacitive deionization (CDI) & Electronic Water Purifier (EWP)
Adsorption	
○ Adsorption	○ Gas hydrates
○ Ion Exchange	○ Sal-Proc™, ROSP, and SEPCON
Oxidation/Disinfection	
○ Ultraviolet Disinfection	
○ Oxidation	

The user inputs criteria such as water quality, water quantity, desired water recovery, and other site-specific operational objectives to assist in the selection of treatment processes. The user can also include or exclude certain treatment processes, such as including or excluding SWRO in the selected treatment train. Using these inputs, along with a robust selection methodology, the tool generates potential treatment trains capable of treating flowback and produced water to a quality suitable for each pre-programmed or user defined beneficial use. The TSM preferentially selects the minimum number of processes, in a logical order, required to treat a given feed water stream for beneficial use t. The TSM generates a report detailing three suggested treatment trains with estimated product water quality and quantity, chemical and energy requirements, brine quality and quantity, and a proposed brine management strategy for each beneficial use option.

2.2.3 Beneficial Use Screening Module (BSM)

The Beneficial Use Screening Module (BSM) stores 10 beneficial use options as listed below:

- Potable use, aquifer recharge, storage & recovery
- Livestock, impoundments, dust control
- Crop irrigation, non-potable use
- Environmental Restoration, Wetlands
- Surface water discharge, instream flow augmentation, fisheries
- Disposal via deep well injection
- Thermal power plant cooling
- New Mexico - Surface water standards
- Hydraulic fracturing gel systems
- Hydraulic fracturing slickwater systems

Each of the beneficial use options is assigned appropriate product water quality requirements that the treatment train needs to achieve. The user can also enter their specific water quality parameters of interest.

2.2.4 Beneficial Use Economic Module (BEM)

The Beneficial Use Economic Module (BEM) calculates costs based on selected treatment technologies, desired product water flow rate, and economic inputs assigned by user. The outputs include unit cost in US$/gallon or other cost units, annual cost in US$/year for capital cost, operation and maintenance cost, and energy consumption. Capital and O&M costs presented in the BEM were developed based on specific design criteria defined through the TSM, general project criteria based on professional experience, and unit costs for power, chemicals and labor. This cost estimate was developed to compare the treatment processes at a Class 5 level representing Planning to Feasibility level information with an estimated accuracy range between -30% and +50%.

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SECTION 3

MARCELLUS SHALE AND BARNETT SHALE CASE STUDIES

3.1 INTRODUCTION

To demonstrate the application of the i-DST for selecting the treatment technologies and evaluating the beneficial use feasibility of hydraulic fracturing flowback and produced water, the Marcellus Shale in Pennsylvania and the Barnett Shale in Texas were selected as case studies. The produced water treatment technologies and beneficial use options were evaluated considering realistic site-specific conditions, assumptions, and future projections such as well numbers, water demands, flowback and produced water quality and quantity, disposal availability, and costs. The tool compared costs of treatment and beneficial uses of produced water scenarios to existing produced water disposal costs. In this way, the tool may be used to perform a quick screening and break-even point for treatment relative to disposal under site-specific conditions.

3.2 CASE STUDY SETUP

To evaluate the beneficial use potential of flowback and produced water, case studies were conducted using the i-DST for the Marcellus Shale in Pennsylvania and the Barnett Shale in Texas. Projections of population and number of producing wells were modeled to estimate future water demand for agricultural uses and hydraulic fracturing. The quantity of flowback and produced water generated during shale gas exploration and production was estimated based on historical data and production trend. Water treatment technologies were selected to meet the water quality requirements of different beneficial uses. After estimating both feasibility and costs of flowback and produced water treatment and disposal, management strategies and beneficial reuse potentials were assessed and optimized by ranking user defined criteria such as technical viability, adoptability, costs, energy and chemical demand, and labor skill requirement.

3.2.1 Study Field – Marcellus Shale

The Marcellus Shale is the largest natural gas producing play in the U.S., and is rapidly growing in recent years, especially in Pennsylvania (Amico et al., 2013; Veil, 2013). The number of total shale gas producing wells in Pennsylvania was 6,391 as of Oct. 10, 2013 (Amico et al., 2013). Flowback and produced water reuse has increased remarkably from 15% to 20% in 2009 to approximately 90% in 2013, mainly for new well drilling (Veil, 2013). Beneficial reuse of the wastewater makes up to approximately 10% of the water needed for hydraulic fracturing job for a new well. Disposal well injection is also used in the Marcellus Shale, with annual volume of approximately 2.5 million barrels (0.4 million m^3). The number of deep injection wells (salt water disposal wells, SWD) is limited in Pennsylvania: only eight SWD wells are permitted to dispose shale gas flowback and produced water, five of which are active as of 2012, and two permits pending (Figure 3.1). These SWD wells are Class II wells regulated by the United States Environmental Protection Agency (USEPA) Underground Injection Control program under Safe Drinking Water Act.

Tioga County and Washington County in Pennsylvania were selected for specific case study due to their locations and number of shale gas producing wells (Figure 3.1). Both counties have high density of shale gas wells and available water quality data. Tioga County is far from disposal wells, while Washington County is close to injection wells and Ohio State where more disposal wells are available. Hauling cost was estimated to range from \$4/bbl to \$8/bbl (\$25/m^3 to \$50/m^3) in Pennsylvania, while injection cost was estimated to be \$0.50/bbl to \$2.50/bbl (\$3.14/m^3 to \$15.72/m^3) (McCurdy, 2011). Pipeline cost was calculated assuming an average 10-mile distance from a wellhead to treatment facilities/impoundments.

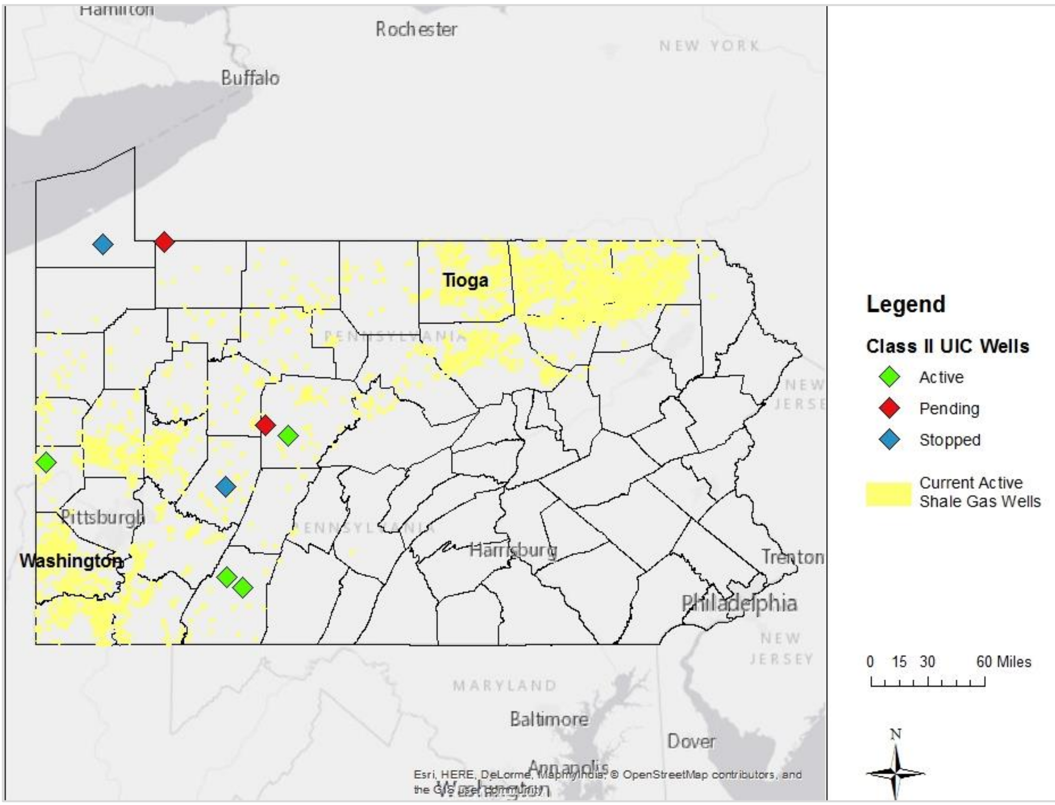

Figure 3.1 Map of Marcellus shale gas wells and deep injection wells in Pennsylvania

3.2.2 Study Field – Barnett Shale

During its development, the Barnett Shale became a major shale gas production field in the U.S. in 2008 when horizontal drilling techniques were first adopted and refined (Figure 3.2). By the end of September 2013, there were in total 17,332 shale gas wells in the Barnett Shale, producing more than 5.3 billion cubic feet shale gas per day (RRC, 2013a, 2013b). Disposal well injection is the most common choice for Barnett Shale producers because of its economics and availability. Lower hauling and injection costs were reported in the Barnett Shale, as there are adequate injection wells. Hauling cost is estimated to be \$1.00/barrel/hour, while disposal cost is \$0.5-\$1.0/barrel. Some producers are reusing a small amount of wastewater, and many have started considering beneficial use options. The Railroad Commission of Texas recognizes concerns over water use by the oil and gas industry and encourages recycling projects to reduce the amount of fresh water used in exploration and production (RRC, 2013c).

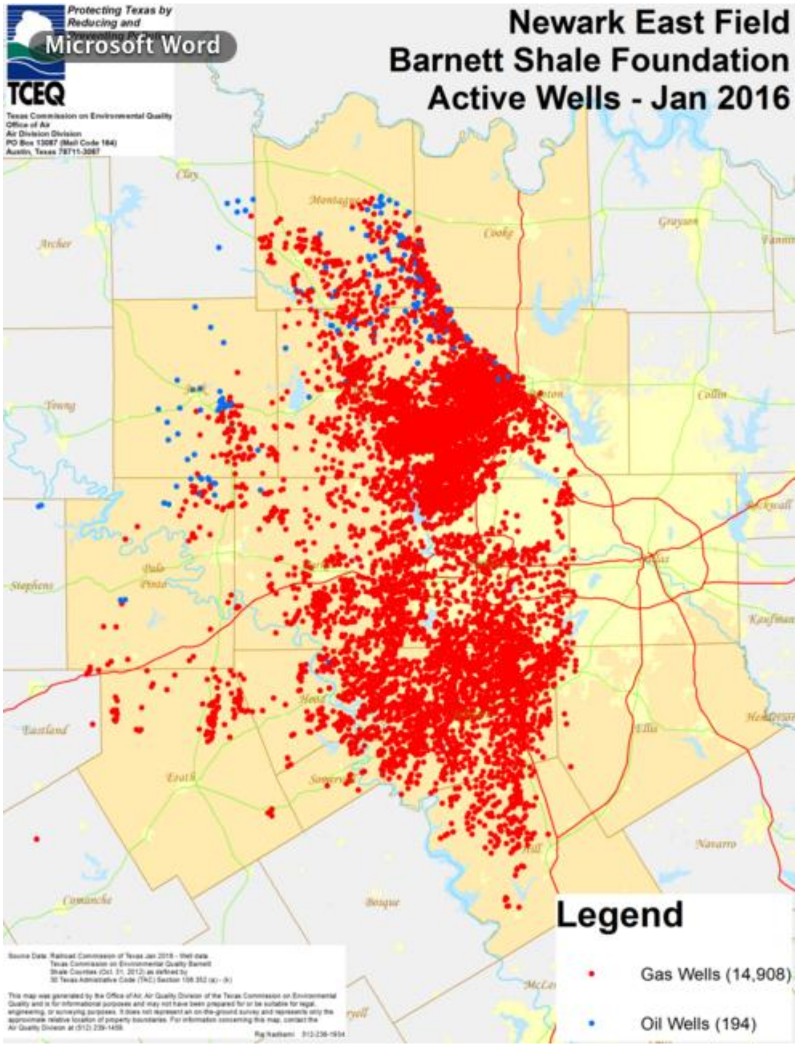

Figure 3.2 Map of the active wells in Barnett Shale. *Source: www.tceq.state.tx.us*

3.3 DATA COLLECTION AND ANALYSIS

3.3.1 Projection of Flowback and Produced Water Quantity

3.3.1.1 Flowback water quantity in Marcellus Shale and Barnett Shale

The Marcellus flowback water quantity was calculated based on the portion of injected hydraulic fracturing liquids that returns to the surface and forms flowback water. The Susquehanna River Basin Commission (SRBC) reported an average of 6% of injected water could be recovered as flowback water (Hansen et al., 2013). Another research calculated a recovery rate of 7% based on the ratio of flowback water to total water demand (Lutz et al., 2013). The annual water demand and flowback water generation in the Marcellus Shale is provided in Table 3.1. In this case study, an average of 6.5% was taken as flowback water recovery rate. Based on the projected water demand corresponding to historical high and low gas production in the Marcellus Shale, the projection of flowback water quantity is illustrated in Figure 3.3. The calculated flowback water quantity for the year 2010 was 470 million gallons (1.78 million m^3), while the quantity reported by industry was 485 million gallon (1.84 million m^3) in 2010 (PSE, 2011). This 3.1% difference is considered acceptable for flowback water projection, indicating that the projection data would be reasonable to calculate future flowback water production used in this case study.

Flowback water quantity in the Barnett Shale was reported to be 500,000 – 600,000 gallons per well within 10 days after hydraulic fracturing (Mantell, 2011). In this case study, the average flowback flow rate was assumed 55,000 gallons per well per day.

Table 3.1 Hydraulic fracturing flowback water recovery in the Marcellus Shale

	Annual Water Demand[1]		Flowback Water Quantity[1]		Calculated Recovery	SRBC Recovery[2]
	Mgal	1,000 m^3	Mgal	1,000 m^3		
2008	10.4	39.4	0.8	3.0	8%	--
2009	40.0	151.3	3.8	14.3	9%	9%
2010	74.4	281.7	3.6	13.7	5%	5%
2011	85.6	323.8	6.1	23.2	7%	4%
2012					--	5%
Average					7%	6%

Note: [1] Source: Lutz et al., 2013; [2] Source: Hansen et al., 2013.

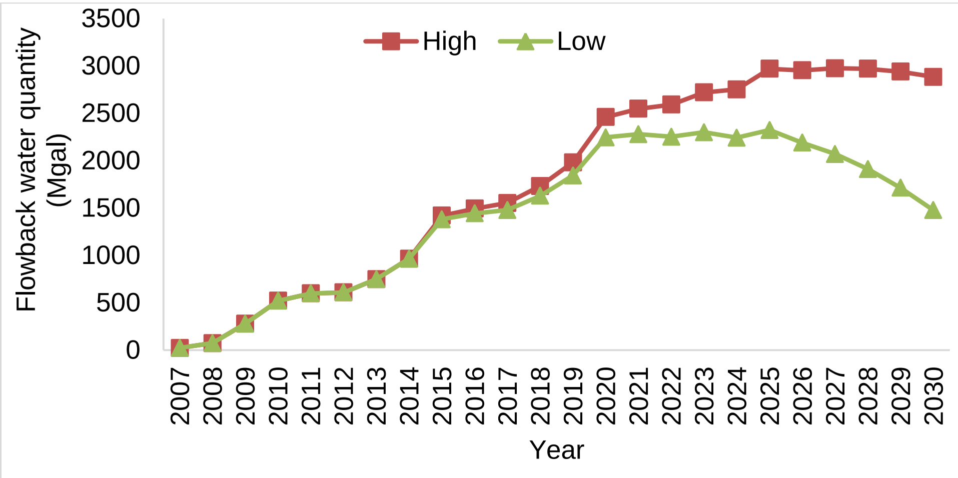

Figure 3.3 Flowback water quantity projected under historical high and low demand conditions based on gas production.

3.3.1.2 Produced water quantity in Marcellus Shale and Barnett Shale

Because there is lack of produced water quantity data over well lifetime for the Marcellus and Barnett shale, produced water quantity projection was based on a study of flowback and produced water volume in Denver Basin, Wattenberg, Colorado (Bai et al., 2013). A harmonic function provided good fit to observed data, and is expressed as:

$$q_t = q_i/(1 + D_i t) \qquad (1)$$

where q_t is produced water flow rate at time t, q_i is the initial water production rate, and D_i is the initial decay rate (Bai et al., 2013).

After applying the water quantity data from the Marcellus Shale Coalition Database, average values of qi and Di were estimated, and the equation of produced water production as a function of well time for the Marcellus Shale is described as:

$$q_t = 15.5/(1 + 2.718t) \qquad (2)$$

Produced water quantity of a shale gas well for the first year was assumed to be 12.1 bbl/day based on industry reported values (Bai et al., 2013).

Compared with the Marcellus Shale, the Barnett Shale is a "high long-term produced water generating play". Barnett shale wells generate 5 times more produced water than Marcellus wells (Mantell, 2011). Based on Equation 1, produced water flow rate for a Barnett shale well as a function of well time was estimated as:

$$q_t = 15.5/(1 + 0.4t) \qquad (3)$$

Comparison of produced water generation between the two basins is shown in Figure 3.4.

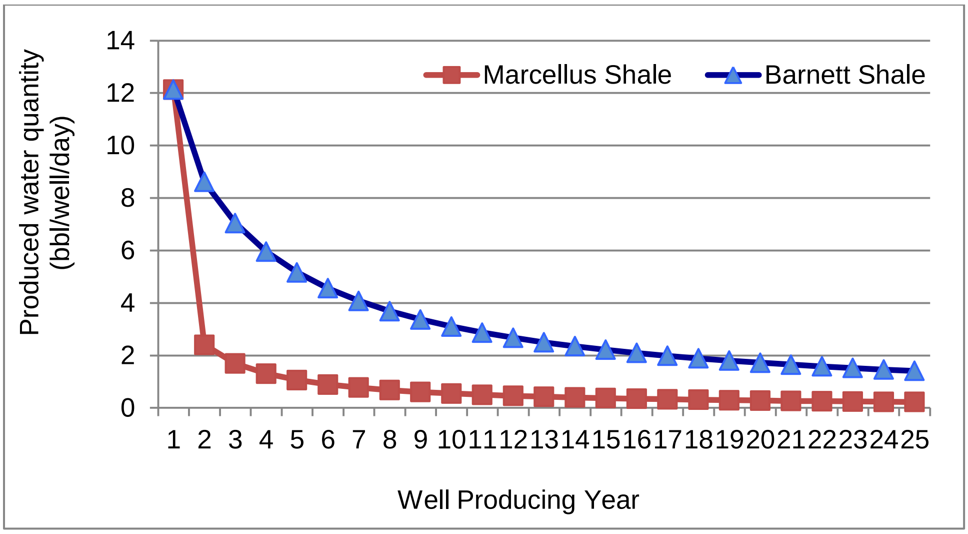

Figure 3.4 Comparison of produced water quantity between the Barnett Shale and the Marcellus Shale

3.3.2 Flowback and Produced Water Quality

In the case study, the quality of flowback and produced water was assumed to be stable over the lifetime of a well. Although flowback water quality changes significantly within the first few weeks after fracturing, its overall quality was considered stable because of its smaller volume and mixing during storage in a pond before treatment or disposal.

Flowback and produced water quality data for the Marcellus Shale were retrieved from the U.S. Geological Survey (USGS) National Produced Waters Geochemical Database v2.1 (Provisional) and the Marcellus Shale Coalition Shale Gas Produced Water Quality Database for Marcellus Shale in Pennsylvania. After quality assurance and quality control (QA/QC), the average TDS of produced water in Marcellus Shale is 87,200 mg/L Pennsylvania, and 77,000 mg/L in West Virginia.

Fracturing flowback and produced water quality data of 19 wells in the Marcellus Shale were collected and reported in the Marcellus Shale Coalition Produced Water Database. A total of 65 TDS values were reported in the database as flowback and produced water, and 19 were reported as influent water stream (water used for hydraulic fracturing). Water quality data at day 1, 5, 14, and 90 were collected following the hydraulic fracturing job. Flowback water quality data distributed evenly, approximately 25-30%, in each TDS category of <8,000 mg/L, 8,000 – 25,000 mg/L, 25,000 – 70,000 mg/L, 70,000 – 140,000 mg/L, and >140,000 mg/L (Figure 3.5). Wells with flowback water TDS over 140,000 mg/L accounted for 15.1% of total monitored wells. 5.7% wells generated water with TDS less than 8,000 mg/L. Twelve produced water quality data sets were reported in the database, of which a majority of wells (91.7%) have produced water quality over 140,000 mg/L (Figure 3.6). The TDS of flowback water increased overtime and reached produced water TDS level in 14-90 days, as illustrated in Figure 3.7.

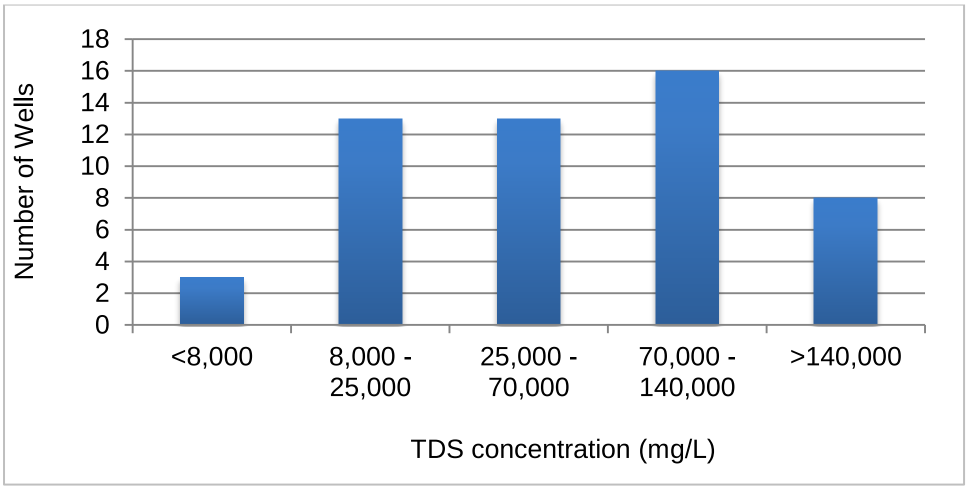

Figure 3.5 TDS concentrations of flowback water reported in the Marcellus Shale Coalition Produced Water Quality Database

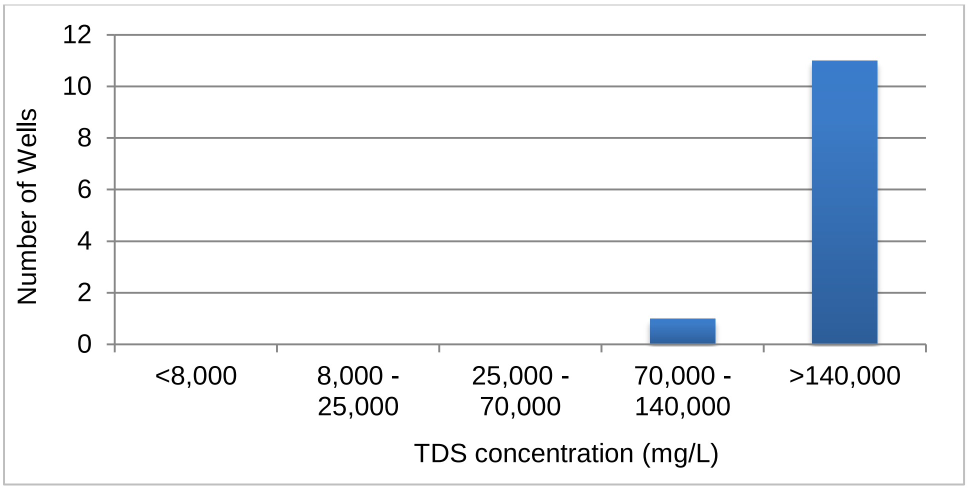

Figure 3.6 TDS concentrations of produced water reported in the Marcellus Shale Coalition Produced Water Quality Database

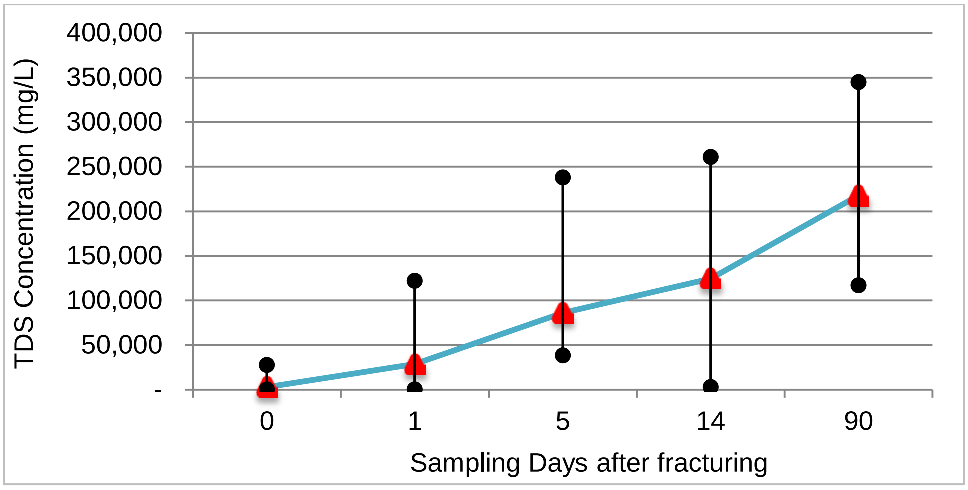

Figure 3.7 TDS concentration of flowback water over time in the Marcellus Shale

As compared to the Marcellus Shale, the flowback and produced water quality data for the Barnett Shale were very limited and not included in the USGS National Produced Waters Geochemical Database. The data were mainly retrieved from a study conducted by Hayes and Severin on the Barnett and Appalachian shale water management and reuse technologies (Hayes and Severin, 2011). This study reported the Barnett Shale flowback water quality data from 5 wells on Day 1, 3, 5, 6, 7, 10, and 12. The average TDS of flowback water was 37,800 mg/L. Produced water quality data for the Barnett Shale were obtained from multiple sources (Li, 2013; Mantell, 2011). The average TDS of produced water was 67,285 mg/L.

3.3.3 Beneficial Uses

According to the US Census of Agriculture data of Pennsylvania farms, both Tioga County and Washington County have more than 1000 farms, which makes agricultural irrigation water use significant. Thus, beneficial use for irrigation was included in this case study.

For this case study, 100% of the flowback and produced water was assumed to be collected and reused. Reuse options included hydraulic fracturing using gel system and slickwater system, and crop irrigation. Water quality requirements for these beneficial use options were previously stored in the BSM, and utilized in the TSM as target water qualities. Potable use of produced water was not considered in this study due to high salinity, economic consideration, and potential public perception issues.

Water quality requirements for beneficial uses in Pennsylvania are shown in Table 3.2, where Class B is for edible crop irrigation and Class C for non-edible crop irrigation (PADEP, 2012). TDS requirement for irrigation varies depending on the types of crops and soil. This study used a 1,500 mg/L TDS concentration as irrigation water requirement. Surface discharge requires water quality no worse than Class A requirement, and the TDS requirement was assumed less than 500 mg/L. Other contaminants that required by primary and secondary drinking water standards set by the USEPA are also required in Class A water quality standard, which is regulated for potable water use, drinking water aquifer recharge, and other residential uses (PADEP, 2012).

The quality of the water is important for hydraulic fracturing because impurities can reduce the efficiency of the additives used in the process. However, there is lack of common standards used to determine the quality requirement of the water for fracturing; it is highly dependent on the formation, the fracturing methods and chemicals added in the process. In this study, it is assumed that slickwater system requires water with TDS lower than 40,000 mg/L, while cross link gel system does not have strict TDS requirement but have specific requirements on certain ions as listed in Table 3.3. These water quality requirements are only examples; the user can enter their specific water quality requirement in the i-DST.

The water quality beneficial use requirements in the Barnett Shale were assumed the same as in the Marcellus Shale in the case study.

Table 3.2 Water quality requirements for irrigation in Pennsylvania

Contaminants	Monthly Average (mg/L)	Max (mg/L)
Class A: potable water use, surface water discharge		
Biochemical oxygen demand (BOD)	2	5
Total organic carbon (TOC)	10	
Turbidity	2 NTU	5 NTU
Fecal Coliform	2.2/100 mL	23/100 mL
Total organic halogens (TOX)	0.2	
Total Nitrogen	10	
Class B: edible crop irrigation		
Biochemical oxygen demand (BOD)	10	20
Turbidity	10 NTU	15 NTU
Fecal Coliform	2.2/100 ml	23/100 mL
Class C: non- edible crop irrigation		
Biochemical oxygen demand (BOD)	30	45
TSS	30	45
Fecal Coliform	200/100 mL	800/100 mL

Table 3.3 Hydraulic fracturing water quality requirements

Hydraulic Fracturing System	Cross Link Gel System	Slickwater System
pH	6.0 - 8.0	> 5
Hardness (Ca+Mg)	< 2,000 mg/L	-
Iron	< 20 mg/L	-
Sulfate	200 - 1,000 mg/L	-
Chloride	< 40,000 mg/L	-
Bicarbonate	< 1,000 mg/L	-
Boron	< 10 mg/L	-
Multivalent Ions	-	< 5,000 mg/L
TDS	-	< 40,000 mg/L

3.4. CASE STUDY RESULTS

3.4.1 Marcellus Shale

3.4.1.1 Tioga County produced water, Marcellus Shale

Produced Water Quality and Quantity

According to the State Impact Project by the National Public Radio (NPR), there are 640 active shale gas wells in Tioga County owned by 9 operators (Amico et al., 2015). The TDS concentration reported in the USGS database ranges from 746 mg/L to 358,000 mg/L, while the average value is 88,500 mg/L, much higher than most beneficial use water quality requirements. Average total suspended solids (TSS) concentration is 468 mg/L, alkalinity 114 mg/L as $CaCO_3$, and total hardness (Ca^{2+} and Mg^{2+}) 768 mg/L. Table 3.4 summarizes the major water quality parameters of produced water in Tioga County.

Table 3.4 Major produced water quality parameters in Tioga County

Parameter	Unit	Max	Min	Average
Alkalinity (as $CaCO_3$)	mg/L	191	8	114
Calcium	mg/L	1,950	43	706
Chloride	mg/L	151,000	42	31,690
Magnesium	mg/L	167	6	62
Potassium	mg/L	106	2	39
Sodium	mg/L	11,700	21	3,624
Sulfate	mg/L	44	0	19
Total dissolved solids (TDS)	mg/L	358,000	746	88,496
Total suspended solids (TSS)	mg/L	1,150	10	468
pH		7.4	4.33	6.59

The produced water production in Tioga County was projected for the next 15 years based on Equation 2 and the number of existing wells in the county. In this case study, shale gas wells were grouped by operators, that is, produced water from all the wells operated by the same operator would be collected, treated by clustered treatment facilities, and reused. Produced water quantity for each operator was assumed to be proportional to the number of wells they own. Two companies that own the most wells (386) and the least well (one) in Tioga County were chosen to represent two extreme production conditions in Tioga County. Company A represents the scenario of clustered produced water treatment collected from 386 wells while Company B with only one well represents wellhead produced water treatment. The two scenarios are represented by the high flow rate scenario and low flow rate scenario, with flow rates at 0.394 million gallons per day (MGD) (9,373 bbl/day) and 320 gallons/day (7.73 bbl/day), respectively.

Treatment Technology
For the Tioga County case study, a summary of treatment technologies selected by the DST for various beneficial use purposes is shown in Table 3.5.

No desalination is required for hydraulic fracturing using gel systems, as it does not have a limit on TDS concentration. Treatment, however, is required to remove suspended solids, sparingly soluble salts, and inactivate microorganisms. Hydraulic fracturing using slickwater method requires pre-treatment to remove suspended solids and sparingly soluble salts, and desalination process because of its 40,000 mg/L TDS limit and other ion concentration requirements. Reuse for hydraulic fracturing requires disinfection because micro-organisms growth reduces the viscosity of fracturing fluid by breaking down the gelling agent, which then reduces fracturing result. Mechanical vapor compressor (MVC) was selected as desalination technique for the produced water with salinity of 88,500 mg/L.

Table 3.5 Produced water treatment trains for Tioga County by beneficial use purposes

Beneficial Use	Treatment Train
Gel	Chemical precipitation - Media filter - Chemical Disinfection
Slickwater	Chemical precipitation - Media filter – MVC - Product Water Blending
Class B Irrigation	Chemical precipitation - Media filter - MVC - Product Water Blending

Scenario Costs
Scenario costs for Company A and Company B were calculated and compared in order to represent the highest and lowest produced water flow scenarios in Tioga County (Table 3.6). Among the three beneficial use scenarios, hydraulic fracturing using gel system had the lowest capital and O&M costs because of its low product water quality requirement especially no TDS limit. Hydraulic fracturing using slickwater system ranked the second; it has higher electrical energy demand, and the desalinated water is blended with filtered water to meet the water quality requirement.

For all the case study scenarios, the life-time of treatment facilities was assumed 10 years. Capital costs and O&M costs for the three beneficial use options did not differ considerably at low flow rate scenario (simulating wellhead treatment), because of smaller facility size and less labor requirement. Total annualized costs ranged from $256,800/year to $259,200/year. At high flow rate scenario, however, the cost differences among the reuse options became significant. The annual O&M costs of reusing produced water for slickwater system and irrigation were approximately 2 times higher than that for gel system. Capital costs were approximately $4.9 million for gel system, $8.3 million for slickwater system, and $8.3 million for irrigation use. Adding capital costs and O&M costs together, Figure 3.8 illustrates the relationship of total annual costs for different beneficial use options. At low flow rate, annual unit O&M costs were approximately $1.9/gal, while total annual unit costs were approximately $2.2/gal. At high flow rate, gel system had the lowest O&M and total costs, \$0.003/gal and \$0.007/gal, respectively, while the costs for hydraulic fracturing using slickwater system and irrigation were estimated to be \$0.005/gal and \$0.011/gal, respectively.

Table 3.6 Summary of produced water treatment costs for Tioga County by beneficial use options

Beneficial use scenario	Capital Cost (\$)	Unit O&M (\$/gal)	Total Annualized Unit Cost (\$/gal)	Energy Consumption (Kwh/yr)	Score
Low Flow Rate (320 gallons per day)					
Gel	329,500	1.898	2.199	100	16
Slickwater	348,300	1.901	2.219	3,700	32
Class B Irrigation	348,200	1.901	2.219	3,700	43
High Flow Rate (0.394 MGD)					
Gel	4,894,300	0.003	0.007	1,312,500	20
Slickwater	8,363,800	0.005	0.011	4,546,000	36
Class B Irrigation	8,258,000	0.005	0.011	4,546,000	51

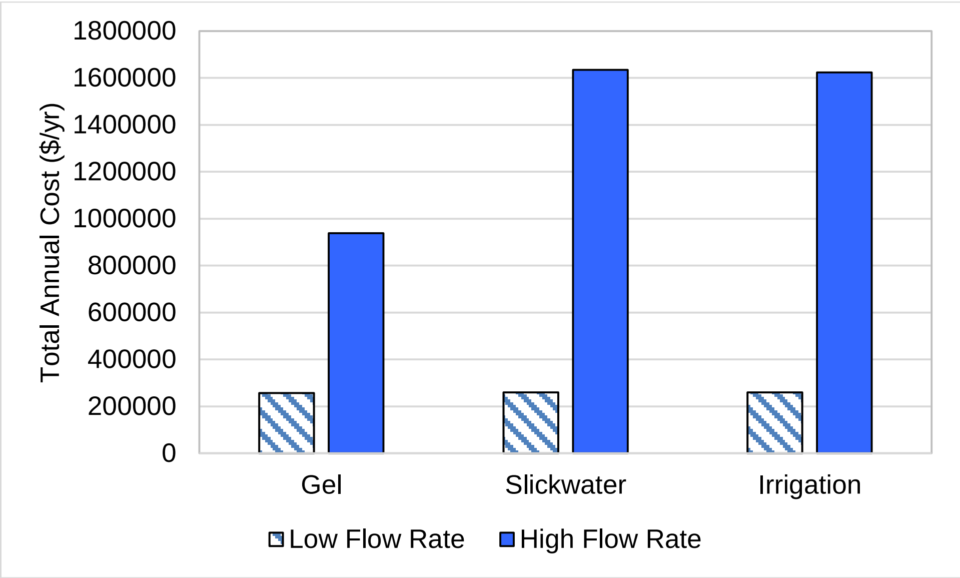

Figure 3.8 Total annual cost for high and low flow rate scenarios in Tioga County

Scores for each beneficial use option stand for the feasibility to reuse each option under this scenario based on user assigned "User Scores". Lower score means higher preference. Performance shows the efficiency of contaminant removal of each treatment train to achieve the target water quality for each beneficial use option. In this study all treatment trains achieved 100% performance. Potential lower performance would be caused by lack of capacity to remove significant high TDS concentrations.

Cost Comparison of Beneficial Uses, Deep Well Injection and Transportation in Tioga County

Deep well injection is the most commonly used disposal method for shale gas produced water because of its low cost. In Pennsylvania, however, the number of injection wells is very limited because of the inappropriate geological condition of the formation. Among the five active injection wells that accept wastewater from oil and gas industry, the nearest one is over 120 miles from Tioga County, which makes transportation cost significantly high. An estimated $8/bbl hauling cost of produced water was assumed for Tioga County (McCurdy, 2011). Injection cost generally ranges from $0.5/bbl to $2.5/bbl. Considering the supply and demand relationship in Pennsylvania, $2/bbl of injection cost was assumed for this case study, resulting in an overall disposal cost (including deep well injection and transportation) of $10/bbl ($0.238/gal).

Using “trial and error” for the i-DST, flow rates of 170 bbl/day for gel system was required to achieve the deep well injection disposal cost equivalent to the treatment cost of produced water. Assuming a produced flow rate of 2-3 bbl per well per day, reuse of produced water for a group of at least 60-100 wells would be more cost-efficient than disposal using deep well injection. Considering all operators in Tioga County, 3 out of 8 operators own more than 60 wells, while all others own less than 30 wells. Centralizing produced water from multiple operators and treating the water collectively would be recommended for small operators to minimize treatment costs.

It should be noted that the cost for purchasing freshwater for hydraulic fracturing was not included in the cost analysis, which would bring additional benefits for reusing flowback and produced water.

3.4.1.2 Washington County produced water, Marcellus Shale

Produced Water Quality and Quantity

By 2014, there were 1094 shale gas wells in the Washington County owned by 10 operators according to the NPR report (Amico et al., 2015). Two companies operating 748 wells and 1 well were chosen to simulate different produced water quantity scenarios, with flow rates at 0.889 MGD (21,174 bbl/day) and 350 gallons per day (8.38 bbl/day), respectively.

Compared with the Tioga County, the TDS concentration and pH of produced water in the Washington County are almost the same. However, reported major ion concentrations in the Washington County produced water are higher than the Tioga County water (Figure 3.9). Calcium concentration of produced water in the Washington County is 16 times higher than that of Tioga County, chloride 2 times, magnesium 18 times, potassium 7 times, and sodium 6.7 times higher. It should be noted that these concentrations used in the case study were the average values from the produced water quality database, and the electroneutrality of the water samples may not be balanced. The TSS concentration, unlike other parameters, is 3 times lower than that of the produced water in Tioga County. This produced water quality difference would lead to a higher treatment cost for beneficial use of produced water in Washington County due to higher hardness concentration.

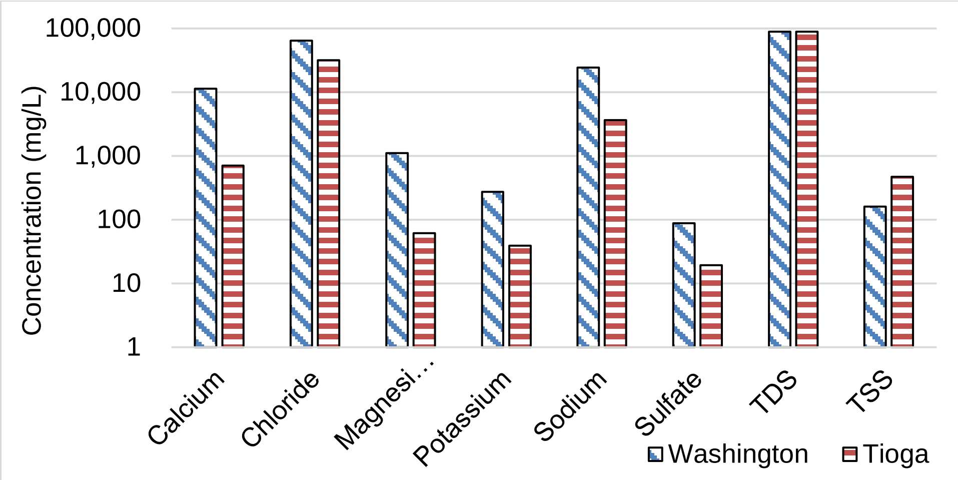

Figure 3.9 Comparison of major constituents between the produced waters in Washington County and Tioga County, Marcellus Shale

Produced water flow rate over time for Washington County has similar trend as Tioga County. High flow rate scenario in Washington County has higher flow rate than in Tioga County, which leads to lower unit costs. Operators with the least wells in both counties have 1 well, which makes their flow rates similar, thus almost the same costs.

Treatment Technology

Treatment processes for the three reuse options given by the i-DST are the same, starting with chemical softening and precipitation, followed by media filtration to remove particulate matters including suspended petroleum hydrocarbon. Although salinity level is not required for hydraulic fracturing using gel system, MVC was selected to reduce chloride concentration to lower than 40,000 mg/L. The product water is required to blend with filtered produced water to meet water quality requirements. MVC was also selected for hydraulic fracturing using slickwater system and for irrigation use, to reduce salinity level to the required concentration. As MVC produces pure water, blending with filtered produced water is required to reach the water quality requirement for different beneficial use purposes.

Scenario Costs

As same treatment processes were assigned to the three beneficial reuse options, the i-DST gave same costs for different beneficial use scenarios – \$2.03/gal for low flow rate of 350 gallons per day, and \$0.01/gal for high flow rate of 0. 889 MGD. Because the costs estimated in the i-DST was at a Class 5 level with an estimated accuracy range between -30% and +50%, the costs estimate was not sensitive enough to reflect the amounts of chemicals used, such as lime and soda, to achieve different product water qualities. The difference of costs between low flow scenario and high flow scenario is significant. Low flow scenario requires much lower capital cost and annual energy consumption, but has a higher unit cost (Table 3.7).

Table 3.7 Cost summary for reusing produced water in Washington County by beneficial use options

Beneficial use	Capital Cost ($)	Unit O & M ($/gal)	Total Annualized Unit Cost ($/gal)	Energy Consumption (Kwh/yr)	Score
		Low Flow Rate (350 gallons per day)			
Gel	353,300	1.74	2.03	4,100	47
Slickwater	353,300	1.74	2.03	4,100	47
Class B Irrigation	353,200	1.74	2.03	4,100	58
		High Flow Rate (0.889 MGD)			
Gel	17,139,100	0.0036	0.0098	10,540,800	52
Slickwater	17,139,100	0.0036	0.0098	10,540,800	52
Class B Irrigation	16,900,300	0.0036	0.0097	10,540,800	67

Cost Comparison of Beneficial Uses, Deep Well Injection and Transportation in Washington County

The nearest injection well that accepts oil and gas wastewater from Washington County is approximately 50 miles away in Pennsylvania. Injection wells in Ohio were not included in this case study because of limited information. An estimated hauling cost $4/bbl was assumed, while $2/bbl injection cost was added to get the total cost of $6/bbl ($0.143/gal) for disposal using deep injection wells, which is 40% less than that in Tioga County. Using the same break-even approach as for Tioga County, to balance with the disposal cost, produced water from at least 100 – 165 wells needs to be collected and treated at a clustered facility. In Washington County, only 2 operators own more than 100 wells and can make beneficial use cost-efficiently by themselves. Other operators are recommended to collectively treat produced water and develop clustered treatment systems to decrease the costs. Due to location limitations, however, decision-making has to be taken under careful consideration of geospatial information, transportation costs, cooperation, and liability.

3.4.1.3 Flowback water in the Marcellus Shale

Hydraulic fracturing flowback water quality and quantity information were retrieved from Marcellus Shale Coalition Produced Water Database. Among the 19 wells in the database, Well J is located in Tioga County, and Well B & F are located in Washington County. Water quality for Day 1, 5, 14 and 15 were chosen to represent flowback water. Weighted average of water quality based on daily flow rate was calculated in the i-DST, with a brief summary shown in Table 3.8. Flowback water flow rate for Tioga County was taken as the average value of the 19 wells (878 bbl/day). For Washington County, average flow rate for Well B & F was calculated at 930 bbl/day.

Table 3.8 Summary of major constituents in flowback water in Tioga and Washington County

Water Quality	Unit	Tioga County	Washington County
Alkalinity (as $CaCO_3$)	mg/L	138	90
Calcium	mg/L	981	8,188
Chloride	mg/L	12,307	58,815
Magnesium	mg/L	86	843
Potassium	mg/L	58	273
Sodium	mg/L	5,243	22,783
Sulfate	mg/L	15	90
TDS	mg/L	24,297	97,104
Total Hardness (as $CaCO_3$)	mg/L	3,987	29,441
TOC	mg/L	36	57
TSS	mg/L	516	94
pH		6.93	6.42

Treatment trains for the two counties selected by the i-DST are shown in Table 3.9. Iron (III) and total hardness were required to be removed by chemical softening and precipitation in both counties to prevent scaling and fouling. Because of the low TDS in flowback water in Tioga County, beneficial reuse for hydraulic fracturing using gel and slickwater system did not require desalination, which significantly reduced the costs. Only chemical disinfection was required to inactivate microorganisms. Brackish water reverse osmosis (BWRO) was selected to desalinate flowback water in Tioga County for irrigation. For flowback water in Washington County, MVC was selected for the higher TDS water.

Estimates of the treatment costs for flowback water are summarized in Table 3.10. Unit costs for reusing flowback water in Tioga County are much lower than those for Washington County because of better flowback water quality in Tioga County. Without desalination processes required, reuse of flowback water for hydraulic fracturing using gel and slickwater systems in Tioga County has the lowest costs.

Table 3.9 Treatment trains for reusing flowback water in Tioga and Washington County

Beneficial Use	Treatment Train
	Tioga County
Gel	Chemical softening - Media filter - Chemical Disinfection
Slickwater	Chemical precipitation - Media filter - Chemical disinfection
Class B Irrigation	Chemical precipitation - Media filter - BWRO - Product Water Blending
	Washington County
Gel	Chemical softening - Media filter - MVC - Product Water Blending
Slickwater	Chemical softening - Media filter - MVC - Product Water Blending
Class B Irrigation	Chemical softening - Media filter - MVC - Product Water Blending

Table 3.10 Cost summary for reusing flowback water in Tioga and Washington County by beneficial uses

	Capital Cost ($)	Unit O&M ($/gal)	Total Annualized Unit Cost ($/gal)	Energy Consumption (Kwh/yr)	Score
			Tioga County		
Gel	798,300	0.0173	0.0238	25,900	27
Slickwater	700,900	0.0172	0.0229	14,100	20
Class B Irrigation	1,299,400	0.0178	0.0289	108,500	43
			Washington County		
Gel	531,300	0.1591	0.2009	46,200	42
Slickwater	531,300	0.1591	0.2009	46,200	42
Class B Irrigation	530,200	0.1591	0.2009	46,200	57

3.4.2 Barnett Shale

The case study for the Barnett Shale used similar processes as for the Marcellus Shale. Water quality and quantity data were collected, analyzed, and projected for the future 15 years. The i-DST was utilized to select the optimal treatment trains and estimate treatment costs for various reuse scenarios. The costs were then compared with disposal costs through deep injection wells, and recommendations were made for operators in the Barnett Shale based on the site-specific conditions.

3.4.2.1 Flowback and produced water quality in the Barnett Shale

The flowback and produced water quality in the Barnett Shale is summarized in Table 3.11.

Table 3.11 Major water quality parameters of flowback water and produced water in Barnett Shale

		Average Concentration	
Parameter	Unit	Flowback[1]	Produced Water[2]
Alkalinity (as $CaCO_3$)	mg/L	852	237
Ammonia	mg/L	244	
Barium			42
Calcium	mg/L	1,082	2,242
Chloride	mg/L	23,052	38,149
Magnesium	mg/L	172	253
Iron (III)	mg/L	24	33
Potassium	mg/L	213	
Sodium	mg/L	13,327	12,453
Sulfate	mg/L	689	60
Total Dissolved Solids (TDS)	mg/L	37,800	67,285
Total Hardness	mg/L	4,000	
Total Suspended Solids (TSS)	mg/L	197	
pH		7.13	

1 *Source of flowback water quality data: Hayes and Severin, 2011*
2 *Source of produced water quality data: Li, 2013; Mantell, 2011*

3.4.2.2 Flowback Water Reuse in Barnett Shale

In this case study, the average flow rate of the treatment facility was designed at 1,306 bbl/day (0.055 MGD) assuming flowback water wellhead treatment for Barnett Shale. To reuse the flowback water for hydraulic fracturing using gel system, although TDS is not required, MVC was selected to remove specific ions (e.g., chloride, calcium, and magnesium) exceeding the required limits (Table 3.12). MVC was also selected for irrigation to reduce TDS concentration. As the Barnett Shale flowback water salinity is lower than the requirement of slickwater based hydraulic fracturing liquid, only disinfection was needed to control microorganisms. Table 3.13 summarizes costs and energy consumption for all beneficial uses. Slickwater based hydraulic fracturing has the lowest score, indicating that it is the most favorable beneficial use option, with the lowest costs and energy consumption.

Table 3.12 Treatment trains for beneficial use of flowback water in Barnett Shale

Beneficial Use	Treatment Train
Gel	Chemical coagulation - Media filter – MVC - Blending
Slickwater	Chemical coagulation - Media filter - Chemical Disinfection
Class B Irrigation	Chemical coagulation - Media filter – MVC - Blending

Table 3.13 Costs and energy consumption for beneficial use of flowback water in Barnett Shale

	Capital Cost	Unit O&M ($/gal)	Total Annualized Unit Cost ($/gal)	Energy Consumption (Kwh/yr)	Score
Gel	1,952,700	0.015	0.026	641,600	32
Slickwater	854,200	0.012	0.017	28,000	16
Class B Irrigation	1,938,000	0.015	0.026	641,600	47

There are approximately 144,000 Class II wells in the U.S., of which 20% are salt water disposal (SWD) wells. In Texas, approximately 12,000 SWD wells are currently available for unconventional oil and gas hydraulic flowback and produced water disposal, with disposal cost of $0.5 - $2.5/bbl (McCurdy, 2011). Based on the supply and demand relationship, the disposal cost was assumed to be $0.5/bbl in the Barnett Shale for this case study. An average trucking cost at $0.75/bbl was estimated. The overall cost to dispose flowback and produced water through SWDs was estimated at $1.25/bbl ($0.0298/gal), which is close to the cost to reuse the Barnett Shale flowback water for slickwater based hydraulic fracturing. Compared with the flowback water scenarios in Pennsylvania, the cost of reusing flowback water is much lower in the Barnett Shale. Moreover, as the Barnett Shale has higher density of producing wells, it is easier for the operators to develop clustered or centralized treatment in order to increase the flow rate to reduce the treatment and reuse costs.

3.4.2.3 Produced water reuse in the Barnett Shale

Two producers in Barnett Shale were chosen to represent the most and least wells with the high and low flow rate scenarios of 8,554 bbl/day and 2 bbl/day (0.36 MGD and 84 gallons per day), respectively. No desalination is required to reuse the produced water for hydraulic fracturing using gel system (Table 3.14). MVC was selected to reduce TDS level to reuse produced water for hydraulic fracturing using slickwater system and for irrigation. Product water needs to be blended with filtered produced water to use for irrigation and hydraulic fracturing using slickwater system to achieve desired water quality and to reduce overall costs.

The low flow rate scenario led to a very high unit cost to reuse produced water at $8.8/bbl for all reuse options (Table 3.15). The unit costs in high flow rate scenario were estimated $0.005/gal for gel system hydraulic fracturing to $0.012/gal for sickwater fracturing and irrigation. Reusing produced water for hydraulic fracturing using gel system is the most economical option as no desalination is required, thus lower cost and energy consumption.

Table 3.14 Treatment trains to beneficial use of produced water in the Barnett Shale

Beneficial Use	Treatment Train
Gel	Chemical coagulation - Media filter - Chemical disinfection
Slickwater	Chemical coagulation - Media filter - MVC - Blending
Class B Irrigation	Chemical coagulation - Media filter - MVC - Blending

Table 3.15 Cost summary for produced water reuse in the Barnett Shale

	Capital Cost ($)	Unit O&M ($/gal)	Total Annualized Unit Cost ($/gal)	Energy Consumption (Kwh/yr)	Score
Low Flow Rate (84 gallons per day)					
Gel	325,800	7.59	8.78	-	12
Slickwater	332,100	7.59	8.80	900	28
Class B Irrigation	332,100	7.59	8.80	900	38
High Flow Rate (0.36 MGD)					
Gel	3,841,500	0.0021	0.0054	142,500	18
Slickwater	8,677,000	0.0046	0.0124	4,147,900	34
Class B Irrigation	8,580,500	0.0046	0.0123	4,147,900	50

To break even with the cost for disposal through injection wells, it requires at least 1,550 bbl/day (0.065 MGD) treatment capacity for reusing produced water for gel based hydraulic fracturing. Using the same assumption as in the Marcellus Shale, it requires to treat produced water collected from at least 517 - 1,275 wells for gel based hydraulic fracturing to break even with the costs for disposal. Under the current production conditions in the Barnett Shale, reusing produced water is not economically competitive as compared to disposal through injection wells because of the requirements for large number of wells, cooperation between producers, building collection and treatment systems.

3.5 CONCLUSION

Flow rate and water quality are the two primary factors affecting the costs and feasibility of treating and beneficial use of flowback and produced water. Higher flow rate leads to higher total capital cost and annual O&M cost ($/yr) because of higher plant capacity and more labor requirement, but lower unit costs ($/gal) as capital cost is normalized by flow rate. Meanwhile better flowback and produced water quality reduces the need of treatment processes, thus lower costs.

Reusing for hydraulic fracturing requires the least treatment processes, especially desalination technologies that result in high treatment cost. In addition, onsite reuse for hydraulic fracturing is highly favorable because of reduced water transportation costs. To treat flowback and produced water, thermal distillation is the most frequently selected desalination process because of the high salinity of produced water. Chemical coagulation/precipitation and media filtration are chosen as pre-treatment processes, as produced water often contains substantial amount of suspended solids, petroleum hydrocarbons, and sparingly soluble salts.

Due to the limited number of injection wells, limited injection capacity and high disposal cost, beneficial use of fracturing flowback and produced water is very attractive in the Marcellus Shale, Pennsylvania. Treating and reusing produced water collected from multiple wells (e.g., 100 wells) would make it more cost efficient than disposal ($6-$10/bbl). Clustered treatment systems therefore would be recommended considering the economic scale of treatment costs. Reusing flowback water in the Barnett Shale would be the most cost-efficient for hydraulic fracturing, for its better water quality and higher water quantity. Reusing produced water in the Barnett Shale is currently not economically favorable because of the low disposal cost through SWD wells ($0.5-$2.5/bbl). However, the rapid development of unconventional oil and gas industry would lead to more intensive water demand, which further leads to a higher potential of flowback and produced water beneficial reuse. Also the case study used the average produced water quality to select treatment technologies and estimate costs. Produced water quality can be highly variable, and the treatment and reuse of produced water would be more economically atractive if the produced water quality is better than the average quality of the basin.

The case studies demonstrated that the i-DST is a useful screening tool to select treatment trains and estimate costs for reuse scenarios from current practice of hydraulic fracturing to potential uses such as irrigation. However, it should be noted that the ecological and environmental benefits of reusing flowback and produced water were not included in the case study. In addition, the cost for purchasing freshwater for hydraulic fracturing was not included in the cost analysis, which would bring additional benefits to reusing flowback and produced water.

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